STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, establishing the method and avoided cost calculation for **CONSUMERS ENERGY COMPANY** to fully comply with the Public Utility Regulatory Policies Act of 1978, 16 USC 2601 *et seq*.	)	Case No. U-18090

At the July 31, 2017 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

OPINION AND ORDER

History of Proceedings

The Commission opened this docket in an order issued on May 3, 2016 (May 3 order), and directed Consumers Energy Company (Consumers) to file proposed avoided cost calculation methods and costs in accordance with the requirements of the Public Utility Regulatory Policies Act of 1978, PL 95–617; 92 Stat 3117 (PURPA) and the May 3 order. In its filing, Consumers was instructed to provide avoided cost calculations using: (1) the hybrid proxy plant method proposed in the PURPA Report;[1] (2) the transfer price method developed under 2008 PA 295

[1] In an order issued on October 27, 2015, in Case No. U-17973, the Commission opened an investigation into issues concerning PURPA avoided costs. After a series of meetings and a round of comments, the investigation culminated on April 8, 2016, when the Commission Staff (Staff) filed a final report (PURPA Report).

(Act 295); and (3) another method, if any, that the company wished to propose. Consumers was also directed to file a proposed Standard Offer tariff, including applicable design capacity.

Pursuant to the May 3 order, Consumers filed various avoided cost methods and costs on June 17, 2016. Administrative Law Judge Mark E. Cummins (ALJ) held a prehearing conference on July 21, 2016. At the prehearing conference, the ALJ granted petitions to intervene filed by, among others, Independent Power Producers Coalition of Michigan (IPPC); and Environmental Law & Policy Center, Ecology Center, Solar Energy Industries Association, and Vote Solar (collectively, ELPC). The Staff also participated in the proceedings.

On May 31, 2017, the Commission issued an order (May 31 order) finding: (1) the most appropriate method for determining Consumers' avoided capacity and energy costs is the Staff's hybrid proxy unit method based on the avoided capacity cost of a natural gas combustion turbine (NGCT) and the avoided energy cost of a natural gas combined cycle (NGCC) unit; (2) zonal resource credits (ZRCs) should be applied to intermittent resources like wind and solar; (3) a fixed investment cost attributable to energy (ICE) should be added to the energy portion of avoided costs, as the Staff proposed; (4) a 10-year planning horizon is appropriate for determining whether Consumers requires additional capacity, and if the utility requires any capacity during the planning period, it should pay qualifying facilities (QFs) for both capacity and energy; (5) expiring contracts for existing QFs should be renewed at the full avoided cost rate, whether or not Consumers forecasts a capacity shortfall; (6) if no capacity is needed during the 10-year planning horizon, then Consumers shall make a filing so indicating, and the avoided cost for capacity shall be reset to the Midcontinent Independent System Operator, Inc.'s (MISO's) planning reserve auction (PRA) price; (7) the design capacity for the Standard Offer should be set at two megawatts (MW); (8) Standard Offer term lengths should be set at five, 10, 15, and 20 years at the option of the QF; (9) once quantified, other factors including reduced transmission costs, reduced air emissions and environmental compliance costs, and the hedging value resulting from QF power should be applied to the calculation of avoided cost; (10) a line-loss credit of 2.37% should be applied to the Standard Offer until more information is available, and the credit should be negotiated for other agreements; (11) renewable energy credits (RECs) belong to the QF under both the Standard Offer and negotiated power purchase agreements (PPAs); (12) the next review of Consumers' avoided costs should be conducted in two years; and (13) additional PURPA issues, including rates for stand-by service, back up, and supplementary power are being addressed in other proceedings. The Commission further determined:

> While the Commission adopts the hybrid-proxy approach as the appropriate method for arriving at avoided cost, it nevertheless finds that, with respect to calculating final avoided cost amounts for capacity and energy, there is insufficient information in this record about the proper inputs to the models to arrive at an accurate determination. Considering the number of QFs with expiring contracts on Consumers' system, and the expectation that many of these contracts could be renewed for some period, it is essential that the Commission have a sufficient record on which to make the determination of avoided cost in compliance with the mandates of PURPA. Not only is the establishment of an accurate avoided cost necessary for existing and new QFs, but also for the Commission's benefit in evaluating PPAs and certificates of need for new generation that the company may present in the future. The Commission finds that the inputs to the NGCT proxy for capacity and the NGCC model for energy were not sufficiently examined in the proceeding. Accordingly, the Commission remands this case for the limited purposes of receiving into evidence the appropriate inputs for capacity, capacity factor, heat rate, projected fuel cost, and capital costs plus the amount of the ICE adder, for the Staff's hybrid proxy model.

May 31 order, pp. 19-20.

In accordance with the May 31 order, on June 12, 2017, Consumers, the Staff, ELPC, and IPPC filed testimony and exhibits for the reopened proceeding. Between June 19 and June 26, 2017, the parties filed corrected testimony and exhibits or rebuttal testimony and exhibits.[2] Evidentiary hearings were conducted on June 21 and June 27, 2017. The record in the reopened proceeding consists of 183 pages of transcript and 24 exhibits admitted into evidence. Portions of testimony and some exhibits were filed confidentially and are not available in the public docket.

Review of the Record

Priya D. Thyagarajan, a General Engineer in Consumers' Energy Supply Operations Department, testified regarding the company's updated inputs to the hybrid proxy model and about the company's concerns with respect to the application of ZRCs to QF resources.

Ms. Thyagarajan explained that Consumers' calculation of the fixed cost of a NGCT is contained in Confidential Exhibit A-23 and that the resulting total capital cost is reasonable. Ms. Thyagarajan observed that Consumers' results are within the range reported by MISO in its most recently published cost of new entry (CONE) for an NGCT in MISO Zone 7 of $733 per kilowatt (kW) and the November 2016 report titled "Capital Cost Estimates for Utility Scale Electric Generating Plants" from the Energy Information Administration (EIA) that computed a capital cost for an advanced NGCT of $678/kW. Ms. Thyagarajan continued, explaining that the company's calculation of the fixed cost of an NGCC is contained in Confidential Exhibit A-24, which she again contended was reasonable based on the November 2016 EIA estimate for an advanced NGCC of $1,104/kW. 1 Tr 15.

Ms. Thyagarajan testified that Consumers assumed an average heat rate at maximum output of 6.354 million British thermal units (MMBtu) per megawatt-hour (MWh), a rate that is similar to

[2] Motions to strike and responses to these motions were filed by several parties; however, the motions to strike were subsequently withdrawn.

EIA's November 2016 projection of 6.300 MMBtu/MWh for an advanced unit. According to Ms. Thyagarajan, "This heat rate represents the latest available NGCC technology (H-class) which necessitates higher fixed costs for lower heat rates (higher efficiencies)." 1 Tr 16; Exhibit A-25.

Ms. Thyagarajan indicated that, with respect to projected fuel costs, NGCC variable costs, and energy market prices, the company had used the same method as it had proposed previously, but updated the numbers to more current estimates. 1 Tr 16; Exhibits A-25 and A-26. For the ICE payment part of the avoided cost calculation, Ms. Thyagarajan indicated that a capacity factor of at least 82% should be used, opining that "Recent experience of market conditions and expected market changes seem to foreshadow that capacity factors higher than 61.77%, as proposed by Staff, can be justified. For example, the Company's Zeeland NGCC unit had a capacity factor of 82% in 2016[.]" 1 Tr 17; Exhibit A-27.

Ms. Thyagarajan testified that all of the inputs and projections in Exhibits A-23 through A-27 have been updated and are consistent with both the values Consumers uses for its own internal projections and with the May 31 order. Ms. Thyagarajan stated that the company would file an updated Standard Offer tariff once final avoided costs are approved. *Id*.

Ms. Thyagarajan opined that the Staff's position on the application of ZRCs to the capacity calculation appeared uncertain. Ms. Thyagarajan noted that the Staff recognized the value of the MISO ZRC capacity structure but at the same time only applied this structure to wind and solar. Ms. Thyagarajan added that, although the May 31 order was clear that the ZRC capacity structure should apply to wind and solar; it did not discuss the application to other QF resources. 1 Tr 18-19. Ms. Thyagarajan maintained that it is not appropriate to assign capacity credit based on ZRCs solely to solar and wind. Ms. Thyagarajan asserted that because Consumers receives ZRC capacity credit for all generating units, regardless of the type of unit, it is only reasonable to use the same construct for the avoided cost calculation. 1 Tr 19.

Julie K. Baldwin, Manager of the Renewable Energy Section of the Commission's Electric Reliability Division, presented the Staff's recommended Standard Offer tariff and provided a sample avoided capacity cost calculation in Exhibit S-10. Ms. Baldwin explained that, based on the Commission's findings in the May 31 order, the Staff made a series of updates and clarifications to its previously proposed Standard Offer. These changes include the addition of 20-year energy rates, updated inputs for capacity and energy avoided costs, effective load carrying capacity (ELCC) credits are included for wind and solar, and the tariff is revised to state that RECs belong to the QF. 1 Tr 29-30; Exhibits S-1 and S-9.

Ms. Baldwin described the sources used in developing Exhibit S-10 and explained that the exhibit provides sample avoided cost payments for capacity spread over estimated generation amounts for different QF resources, noting that the actual payment is based on the capacity of the QF in kW. Ms. Baldwin explained that there may be value in a Staff estimate of the monthly payment on a kilowatt-hour (kWh) basis. However, the monthly payment may differ from the payments that the Staff calculated depending on the actual generation of the QF. Finally, Ms. Baldwin recommended that Consumers' Standard Offer be made available the day after the Commission issues its order in this proceeding, and that the company should be directed to file updated tariff sheets within 30 days. 1 Tr 30-31.

In rebuttal, Natalie N. Busack, Senior Rate Analyst II in Consumers' Rates and Regulatory Affairs Department, provided an updated Standard Offer tariff reflective of the May 31 order. Ms. Busack testified that the tariff revisions included: (1) increasing the size limitation for a QF;

(2) indicating that contracts over two years will continue with the capacity and energy rates as specified in their PPAs; (3) updating energy and capacity pricing according to Exhibits A-23 and A-27; (4) updating the term lengths of contracts; and (5) updating early termination payment requirements. 2 Tr 82; Exhibit A-28. Ms. Busack further testified that Consumers disagrees with Ms. Baldwin's recommendation to make the Standard Offer tariff effective the day after the Commission order approving avoided costs, indicating that the company would need more time to incorporate the Commission's decisions and finalize the Standard Offer. Accordingly, Ms. Busack recommended that the Standard Offer be effective five business days after the Commission's order. 2 Tr 83.

Kenneth G. Troyer, Supervisor of the Contract Strategies group in the Supply Operations Department at Consumers, also filed rebuttal to Ms. Baldwin, contending that Exhibit S-10 is not an accurate representation of the costs the company would incur under avoided cost rates, noting that MISO measures usable capacity in ZRCs and not kWhs as shown in Exhibit S-10. Mr. Troyer further testified that Exhibit S-10 shows run-of-the-river hydroelectric facilities are compensated for capacity in the same manner as biomass and landfill gas. According to Mr. Troyer, this is incorrect because MISO considers this type of hydroelectric facility to be an intermittent resource. 2 Tr 109-110.

In response to the Standard Offer tariff sponsored by Ms. Baldwin, William F. Stockhausen, Principal Agent for Michiana Hydroelectric Co. and Elk Rapids Hydroelectric Power LLC, provided rebuttal testimony on behalf of IPPC. Mr. Stockhausen testified that while run-of-the-river hydro members of IPPC agree with adjusting the design capacity of the tariff to 2 MW, with a contract length of up to 20 years, IPPC did not support the inputs to the Standard Offer as proposed by the Staff. 2 Tr 164. Mr. Stockhausen testified that IPPC agreed with ELPC that the

Staff’s use of a real natural gas price forecast was incorrect and that a nominal price forecast should be used. According to Mr. Stockhausen, “the result of these new calculations and inputs will have a chilling effect on continued operations of IPPC members’ hydroelectric facilities, as these corrected rates are unjustifiably and unrealistically low and cannot be said to truly reflect the Company's avoided cost of energy for baseload generation.” 2 Tr 165. Mr. Stockhausen explained that:

> The rates now are more reflective of the off-peak forecasted LMP Energy Rate under Option 2, a market option that the IPPC began, and will end this proceeding, strenuously opposing. The proxy plant model should have improved rates compared to the LMP model, when in fact with the longer term the rates aren't even better than the combined on and off-peak, but in fact are approaching the LMP off-peak.

Id.

Mr. Stockhausen further testified that the rates in Options #2 and #3 do not reasonably escalate over the length of the contract, and “IPPC believes that the standard offer, like the avoided costs for negotiated contracts, should be indexed over time so as to provide a reasonable cost adjustment[,]” claiming that Option #2 increases at about 1% per year, and Option #3 escalates at only .5% per year, compared to the Consumer Price Index that has increased at a rate of approximately 2% per year. 2 Tr 166.

Mr. Stockhausen also took issue with the assumed 2.37% line-loss adjustment, noting that a transformer loss adjustment of 3% should also be made. Mr. Stockhausen opined that the Staff’s proposed rates should be comparable to the transfer price schedule used for the company’s own renewable projects. Mr. Stockhausen recommended that in order to address the many concerns that IPPC has about the Standard Offer, the Commission should convene a technical conference to resolve these issues. 2 Tr 167.

Jesse J. Harlow, a public utilities engineer in the Renewable Energy Section of the Commission's Electric Reliability Division, provided the Staff's final avoided cost inputs and calculations. Mr. Harlow testified that the Staff modified its original hybrid proxy plant calculations by including new inputs that it considers more appropriate, rather than relying on the company's inputs, as it had in its previous testimony and exhibits. Mr. Harlow further observed that the price for avoided capacity and energy the Staff calculated here is substantially similar to a currently pending PPA with T.E.S. Filer City Station Limited Partnership (Filer City PPA) that Consumers filed in Case No. U-18392. 1 Tr 38-39.

Mr. Harlow explained that for the inputs for the capacity portion of the calculation, the Staff used the capital, operations and maintenance, heat rate, size, and performance characteristics that MISO used for calculating the 2017-2018 planning year CONE, resulting in a capacity value of $105,209 per megawatt-year. However, Mr. Harlow noted that the Staff's computed value is approximately $10,000 more than MISO's CONE because the Staff used Consumers' fixed charge rate of 12.709% for an NGCT and a discount rate of 7.65% to provide a more company-specific avoided cost rate. Mr. Harlow testified that the MISO inputs that the Staff used were obtained from MISO in February 2017. 1 Tr 39-40.

For the energy portion of the avoided cost calculation, Mr. Harlow testified that the Staff used updated variable cost transfer price inputs for an NGCC, as filed in Case No. U-15800. Again, the Staff modified the numbers to incorporate Consumers' discount rate and fixed charge rate for an NGCC of 12.742%. In addition, the Staff calculated costs out to 2036 to provide a 20-year projection, and it used a more recent EIA real (rather than nominal) natural gas price forecast adjusted to 2017 dollars. 1 Tr 40-41; Corrected Exhibit S-12. Mr. Harlow explained that "the nominal price forecast would be appropriate if it were utilized on a net present value (NPV) basis only, but since Staff takes the NPV of the gas forecast and applies a change rate based on Global Insight indices that assume an inflation rate, the real price forecast is the most appropriate for this purpose." 1 Tr 42. Mr. Harlow testified that the Staff sees value in using transfer price inputs in computing avoided energy costs, noting that these inputs have been scrutinized in various proceedings.

Mr. Harlow explained that the ICE adder, which represents the difference between the fixed cost of an NGCC, compared to an NGCT, has changed as a result of the updated inputs to these proxy units. Similarly, Mr. Harlow testified that the 15- and 20-year locational marginal price (LMP) projections were derived from extrapolating the LMP projections that the Staff originally filed. 1 Tr 42-43, Exhibit S-13.

Mr. Harlow opined that the hybrid proxy model used here is similar to transfer price; however, transfer price is not appropriate for use in the avoided cost calculation because transfer price is primarily used to allocate costs between power supply cost recovery (PSCR) and regulatory liability; cost recovery is based on the lesser of the transfer price or the actual cost of the project or PPA, and transfer price does not distinguish between capacity and energy costs. 1 Tr 43. Nevertheless, Mr. Harlow pointed to a comparison of the results using the transfer price model and the hybrid proxy model noting that the results of $66.73 per MWh and $63.29 per MWh, respectively, were substantially similar. 1 Tr 44.

In rebuttal, Timothy J. Sparks, Vice President of Energy Supply Operations for Consumers, raised concerns about some of the exhibits presented by Ms. Baldwin and Mr. Harlow. Mr. Sparks explained that unlike transfer price, which is a levelized monthly payment, the monthly payment for avoided cost is based on a fixed payment for capacity and a variable payment for energy produced. Mr. Sparks therefore opined that Exhibit S-10, which shows avoided costs in a single

$/MWh amount, and a portion of Mr. Harlow's testimony comparing avoided cost amounts to amounts paid under the transfer price, could cause confusion. Mr. Sparks therefore recommended that the Commission clarify that avoided cost payments would be comprised of both a fixed and a variable component. 2 Tr 88.

Mr. Sparks also took issue with the Staff's avoided cost inputs, noting that Consumers currently has contracts with approximately 30 QFs with capacity of 20 MW or less. At current avoided costs, the company pays $59 million annually to those facilities. Under the Staff's calculation, this amount would be reduced to $50.1 million. Mr. Sparks pointed to two of Consumers' recent wind PPAs, which, if converted to avoided cost and applied to the 30 QFs, would result in a total annual cost of $37 million. 2 Tr 88-89. Mr. Sparks testified that if the company's proposed inputs were used in the avoided cost calculation, the resulting total payment to QFs would be $40.4 million. 2 Tr 90.

Ms. Thyagarajan disagreed with the heat rate of 6,719 Btu/kWh that Mr. Harlow used in his calculation, contending that the heat rate data Mr. Harlow used is for a generic plant and does not represent the heat rate of an advanced NGCC unit. 2 Tr 98. Similarly, she took issue with Mr. Harlow's assumed capacity factor of 61.77%, which she claimed did not represent the capacity factor for the plant Consumers would build. 2 Tr 103. Ms. Thyagarajan also testified that she agreed with the Staff's gas price forecast using real dollars, noting that, "Using nominal dollars would only be acceptable if the calculated levelized price was being proposed for energy payments in every year of the contract term. If the nominal price of natural gas is levelized and then further escalated, it results in double-counting the impacts of escalation." *Id.*
Ms. Thyagarajan testified that Exhibit A-29 provides Consumers' latest 20-year LMP forecast; thus, it is not necessary to use the Staff's extrapolated LMP estimates. 2 Tr 101.

In rebuttal to Mr. Harlow, Mr. Troyer contended that the Filer City PPA has no relevance to this proceeding because, although Filer City is a QF, its contract is based on avoided costs calculated in 1990, and the PPA is not scheduled to end until 2025. Thus, Consumers is not proposing a new PPA with Filer City based on avoided costs calculated in this case. 2 Tr 112-113. Mr. Troyer further opined that Mr. Harlow's use of EIA inputs does not comport with PURPA, which requires the use of costs that are specific to the utility. Therefore, according to him, the costs that Consumers proposes are the ones that must be used in calculating avoided energy and capacity costs.

Thomas V. Vine, a plant manager for Viking Energy of McBain, LLC, testified on behalf of IPPC and provided proposed inputs to the model approved in the May 31 order. Mr. Vine testified that IPPC relied largely on transfer price inputs for capacity, capacity factor, heat rate, projected fuel cost, and capital costs in its calculation, with adjustments made to reflect company-specific costs. 1 Tr 51; Exhibit IPP-29.

For calculating avoided capacity cost, Mr. Vine testified that IPPC used the 2017 EIA levelized cost estimate for an advanced NGCC, which includes variables for new capacity including capital cost, financing, allowance for funds used during construction (AFUDC), fuel cost, emission regulation, operations and maintenance (O&M), and inflation. 1 Tr 51. Mr. Vine testified that the appropriate heat rate to be used in the calculation is the average annual heat rate, rather than the peak heat rate. According to Mr. Vine, most NGCC units lose efficiency at lower output levels, and he pointed to Consumers' application requesting approval of the Filer City PPA amendment, where the heat rate assumed was 7,600 Btu/kWh, which was likely an average annual heat rate. 1 Tr 52.

Mr. Vine testified that in the Filer City PPA, Consumers used a total O&M cost of $5.00 per MWh, without stating how much of this amount represented fixed O&M and how much was variable O&M. Mr. Vine explained:

> The key variable is total O&M per year. If an NGCC receives $5/MWh for all their O&M, and operates at a 67.45% capacity factor, the NGCC will receive $29,543 per MW-year. This cost can also be divided into distinct fixed cost and variable cost components while maintaining the same total O&M. If variable O&M is priced at $2.4/MWh and the NGCC operates at 67.45% capacity factor, the total variable O&M would cost $14,181/MW-yr. The difference between the total O&M ($29,543/MW-yr) and the variable O&M ($14,181/MW-yr) would be the fixed O&M: $15,362/MW-yr, or $15.36/kW-yr. If a lower fixed variable [sic] O&M cost is used, then an accompanying higher variable O&M cost should be used.

1 Tr 52-53.

Finally, Mr. Vine testified that the Commission should consider treating avoided capacity cost in the same fashion that avoided capacity is treated for Consumers' renewable facilities under the transfer price. 1 Tr 53.

In rebuttal, Ms. Thyagarajan disputed Mr. Vine's use of an NGCC unit in his calculation of avoided capacity costs, noting that the May 31 order was clear that an NGCT was the appropriate unit for developing avoided capacity cost. She further explained that Mr. Vine's capacity cost amount was almost 200% of MISO CONE. Ms. Thyagarajan contended that, because CONE represents the lowest cost capacity build, "Mr. Vine's NGCC capacity cost calculation is not relevant to, and entirely inconsistent with, this case." 2 Tr 95. In addition, she objected to Mr. Vine's use of an ICE adder because the ICE payment is only reasonable if the capacity payment is based on an NGCT. 2 Tr 102.

Ms. Thyagarajan also took issue with Mr. Vine's use of a heat rate of 7,600 Btu/kWh, based on the heat rate referenced in the Filer City PPA, testifying that the heat rate in that case represents what the parties negotiated and is not representative of the heat rate for a new NGCC. 2 Tr 98.

Mr. Troyer pointed out that Mr. Vine inappropriately used a $5/MWh variable cost amount from the Filer City PPA amendment contending, "For the purposes of the Amendment, the $5/MWh is used as a transparent and prescriptive way of determining whether or not the facility would be called by MISO to operate in the day-ahead energy market. Using the $5/MWh value for expected variable cost of any NGCC facility is irrelevant to the Company's avoided costs." 2 Tr 118.

Douglas B. Jester, a partner of 5 Lakes Energy LLC, testified on behalf of ELPC in response to the May 31 order. Mr. Jester recommended that avoided capacity cost be calculated "by normalizing the cost of combustion turbine capacity for effective load carrying capacity and accounting for line losses at peak times[.]" 1 Tr 58. Mr. Jester advocated using the formula:

$$\text{Avoided Capacity Cost}_{QF} = \text{Demand Loss Factor}_{QF} * ELCC_{QF} * CONE_{CT} / ELCC_{CT}$$

> where Demand Loss Factor$_{QF}$ is the average proportional loss at peak times for power delivered from central generating stations to the location of the qualifying facility, [ELCC$_{QF}$] is the capacity credit of the qualifying facility as it will be determined by the relevant authority for resource adequacy purposes, [CONE$_{CT}$] is the first-year capital carrying cost of a hypothetical new combustion turbine plant, and [ELCC$_{CT}$] is the effective load carrying capacity of the hypothetical new combustion turbine plant on which cost of new entry is based.

1 Tr 58-59. Mr. Jester explained that the Demand Loss Factor is "the ratio of generated power measured at the average generator to delivered power, net of transmission and distribution losses, as measured at peak loads." 1 Tr 59. According to Mr. Jester, because capacity is the ability to deliver power on-peak, "the Demand Loss Factor is the appropriate way to adjust the capacity contribution of a qualifying facility." *Id.* Mr. Jester recommended that in calculating avoided capacity cost, the Commission should use the factors, based on different interconnection voltage levels, calculated in Consumers' most recent rate case, Case No. U-17735, as the appropriate Demand Loss Factor. 1 Tr 59-60; Exhibit ELP-12.

With respect to ELCC, Mr. Jester testified that for existing plants, and for new plants of similar design and technology, the North American Electric Reliability Council (NERC) provides Generating Availability Data System (GADS) information that is relied upon by MISO and that can be used here. 1 Tr 61-62; Exhibit ELP-13. For an intermittent resource such as solar, Mr. Jester recommended using the method MISO sets out in its Business Practice Manual 011, noting that due to insufficient data, MISO uses a default of 50% of alternating current (AC) nameplate capacity for solar generation. Nevertheless, Mr. Jester recommended that the MISO default not be used and that the ELCC for intermittent resources "be based upon submission by the qualifying facility and review by the utility of an appropriate engineering calculation." 1 Tr 63-64. Mr. Jester opined that the National Renewable Energy Laboratory (NREL) System Advisor Model (SAM) is an industry-standard tool for these calculations. He therefore recommended that, "the Commission adopt a presumption that an analysis using SAM provides a valid basis for determination of avoided capacity costs of a resource-dependent qualifying facility." 1 Tr 64. Mr. Jester presented a table of sample SAM calculations demonstrating a range of ELCC percentages ranging from 50% to 65% depending on the solar technology and orientation of the array. 1 Tr 65. Mr. Jester further indicated that he supported the Staff's method for calculating CONE and ELCC for an NGCT. *Id*.

For avoided energy costs, Mr. Jester proposed the formula:

Avoided Energy Cost$_{QF}$ = Energy Loss Factor$_{QF}$ * (Variable Energy Cost$_{CC}$ + ICE$_{CC}$)

> where Energy Loss Factor$_{QF}$ is the energy-weighted average annual loss for power delivered from central generating stations to the location of the qualifying facility, Variable Energy Cost$_{CC}$ is the sum of projected fuel and other variable costs of energy from a combined cycle proxy plant, and . . . ICE$_{CC}$ is the difference between the first-year capital carrying cost of a combined cycle plant and the Cost of New Entry$_{CT}$ for load-carrying capacity equivalent to that of the combined cycle proxy plant, allocated to the expected energy production from the combined cycle plant.

1 Tr 65-66; Exhibit ELP-14. Mr. Jester added that the Energy Loss Factor differs from the Demand Loss Factor because the Energy Loss Factor is calculated based on annual losses and the Demand Loss Factor is based on losses at peak times. Mr. Jester recommended that the Energy Loss Factor be based on Consumers' data that has been accepted by the Commission for QF interconnections at different voltage levels. 1 Tr 67; Exhibit ELP-12.

Mr. Jester testified that the Commission should adopt the variable energy cost projections that were used in calculating the most recent transfer prices for the utility unless there is evidence of changed facts between cases. Mr. Jester stated that for ICE, he supports the calculation provided by Mr. Harlow, shown in Exhibit S-6. 1 Tr 68.

Mr. Jester sponsored a Standard Offer tariff based on 2nd Revised Exhibit S-1, with clarifications and recommendations from ELPC. 1 Tr 69; Exhibit ELP-14. Mr. Jester opined regarding the need for the Standard Offer to reflect the Commission's determinations in this case and to "appropriately allocate rights, risk, and responsibilities, and provide for practical development of qualifying facilities." 1 Tr 69.

In rebuttal to the Staff, Mr. Jester, asserted that in his corrected testimony, Mr. Harlow used a real natural gas price forecast and a nominal discount rate, noting that the input for transfer price uses a nominal price forecast and a nominal discount rate. According to Mr. Jester, real prices coupled with a nominal discount rate results in inflation being double-discounted, explaining that real gas prices already account for inflation. Mr. Jester opined that this error results in a 20% decrease in avoided energy costs. 2 Tr 174.

Ms. Thyagarajan agreed with Mr. Jester that ELCC should be calculated for each QF, "However, the use of the Zonal Resource Credit . . . for each individual QF based on annual values calculated by MISO prior to each planning year would be most appropriate to accomplish

Mr. Jester's recommendation." 2 Tr 95. Ms. Thyagarajan disagreed with both Mr. Harlow and Mr. Jester's calculation of capacity payment based on an NGCT, noting that the Staff did not apply ELCC for an NGCT, explaining that "a capacity payment would need to be calculated based on a NGCT in units of $/ZRC, using an expected Equivalent Forced Outage Rate on demand ("EFORd") to discount the Winter Net Demonstrated Capability ("NDC") MW of the NGCT to a ZRC value." 2 Tr 96. Ms. Thyagarajan provided Exhibit A-30, which she testified demonstrates how the Staff's $/MW-year could be converted to $/ZRC. *Id*. Ms. Thyagarajan testified that paying on a $/ZRC basis would encourage QFs to maintain high reliability standards, thereby providing more value to Consumers' customers. 2 Tr 97.

Mr. Troyer disagreed with Mr. Jester's proposed avoided cost calculation methods, testifying that the May 31 order directed that the Staff's hybrid proxy plant method be used for calculating avoided energy and capacity costs, but that Mr. Jester proposed new methods. However, Mr. Troyer did agree with Mr. Jester's use of ELCC, quantified in ZRCs, for resource adequacy purposes. 2 Tr 121. Mr. Troyer explained that if ZRCs are used for resource adequacy in the capacity model, it is not necessary to include line losses, as Mr. Jester proposed, because line losses are included in MISO's calculation of ZRCs. 2 Tr 122. Mr. Troyer also disagreed with Mr. Jester's proposal to apply line losses based on interconnection voltage level to the energy computation, claiming that line losses are site specific and depend on more than voltage level. 2 Tr 123. Finally, Mr. Troyer recommended that, contrary to Mr. Jester's proposal, capacity volume should be adjusted each year based on actual generator output, claiming that this would be fair to both the generator and the company's customers. *Id.*

Positions of the Parties

Consumers argues that the inputs that it provides for an NGCT and NGCC unit are the most appropriate ones for use in the avoided cost calculation because they best reflect the company's costs that are actually avoided. Consumers objected to ELPC's recommendation of a new method for calculating avoided cost, contending that ELPC's proposal went beyond the scope of the order. The company also took issue with IPPC's proposal, arguing that it did not comport with the Commission's directive to use the hybrid proxy method proposed by the Staff.

For the capacity portion of the calculation, Consumers argues that its financial inputs, resource capacities, and capital costs were developed internally and are the costs that the company would actually incur in the event that it built an NGCT unit, adding that the resulting $/kW payment is comparable to MISO CONE and the 2016 EIA cost estimate for an advanced NGCT. Consumers further asserts that capacity should be represented in terms of ZRCs (i.e., $/ZRC-year) because that reflects how MISO assigns capacity. Moreover, Consumers maintains that the MISO ZRC capacity structure should be assigned to all QF resources, not just solar and wind, adding that ZRCs already take line-losses into account, thus addressing ELPC's concerns with respect to accounting for line losses.

Similarly, with respect to the NGCC unit, Consumers contends that its cost estimates were developed internally and represent the type of unit the company would build, noting that the costs are comparable to EIA estimates. Consumers responds to IPPC's criticism, that the EIA estimate does not contain AFUDC, by explaining that the company's cost does contain AFUDC and that the EIA number was simply provided for the purpose of comparison.

Consumers maintains that the heat rate of the NGCC plant that the company would build should be 6.354 MMBtu/MWh, noting that this is close to EIA's 2016 estimated heat rate of 6.300 MMBtu/MWh for an advanced NGCC. Consumers further argues that the heat rate should assume operation of the plant as a baseload unit, rather than as a peaking unit, as IPPC proposes. Consumers states, however, “While the Company believes that there may be some merit to using an average annual heat rate, none of the data submitted from the vendors supports an average annual heat rate above 6.600 MMBtu/MWh.” Consumers’ brief, p. 9. Consumers disputes the Staff’s heat rate assumption of 6.719 MMBtu/MWh, claiming that this is based on EIA data for a generic unit and not the advanced unit the company would build, and it points out that the heat rate advocated by IPPC, based on the Filer City PPA, has no relevance to this proceeding.

For its fuel price projection, Consumers avers that it used the Staff’s method and developed a natural gas price projection in real dollars and multiplied these amounts by the assumed heat rate. For the ICE adder, Consumers again states that it used the Staff’s method updated with updated inputs, including a capacity factor of 82%. Consumers contends that the 82% capacity factor is reasonable, pointing to the company’s Zeeland unit that had a capacity factor of 82% in 2016. Consumers also points out the IPPC’s proposal to add ICE to the energy portion of IPPC’s model is misplaced because IPPC used the same NGCC technology in developing its avoided costs for both energy and capacity.

Consumers argues that it developed fixed and variable O&M costs in accordance with the Staff’s method using “the real dollar delivered natural gas forecast . . . multiplied . . . by the appropriate heat rate[.]” Consumers’ brief, p. 10. With respect to ICE, Consumers explains that it calculated this adder consistent with Mr. Jester’s explanation in the first phase of the case, reiterating that the use of the Staff’s 61.77% capacity factor in the computation is unreasonable based on the 2016 capacity factor of 82% at the company’s Zeeland plant. Consumers disputed IPPC’s claim, based on an integrated resource plan filed in 2013, noting that much has changed since then, including the more economical technology that the company would build today.

Furthermore, Consumers contends that an inflation adjustment need not be applied to O&M costs because those costs are already escalated.

Consumers argues that the Commission should approve the company's proposed Standard Offer tariff set forth in Exhibit A-28, claiming that its tariff is reasonable and consistent with the May 31 order. Consumers stated that it agreed with the Staff's recommendation to use the CON.CETR pricing node for the day-ahead LMP pricing option, with the proviso that the CON.CETR node should not be used for all PPAs. Consumers explains that "The appropriate pricing node and determination of day-ahead or real-time LMPs is facility specific based on several factors which include the connected voltage level, size of the facility, and its operating characteristics." Consumers' brief, p. 21. Similarly, for the LMP forecast option, Consumers recommends that LMP at CON.CETR be specified in the tariff. Consumers also contends that the language in the tariff should clarify that the QF will continue to receive the agreed-to energy and capacity rate through the duration of the contract, noting that rates will change for new contracts whenever the Standard Offer is revised. Consumers also proposed a modification to the early termination clause of the Standard Offer, clarifying:

> The Early Termination provision was updated as a result of the extension of the Standard Offer tariff from ten years to 20 years by the Commission. Company witness Troyer explained that the Company's previously proposed Early Termination provision was designed to allow the Company to recover the expense associated with replacing the lost capacity from the QF due to the QF's failure to perform through the term of the agreement. Under the previous provision for Early Termination, if a QF elects a contract term longer than ten years, the QF would have been placed in a higher level of economic risk. . . . Under the new language proposed, the Company indicates that it will evaluate the financial risk associated with Early Termination for each new QF contract based on the difference between the maximum cost to replace the products associated with the PPA and the cost expected to be paid to the QF under the contract. . . . This will protect the customers from the financial risk associated with early termination of a QF and limits the amount of financial impact to the QF.

Consumer's brief, pp. 22-23 (citations omitted). Lastly, Consumers objects to IPPC's recommendation that the Commission order a technical conference to finalize the details of the Standard Offer. Consumers points out that IPPC had over a year to develop and present a Standard Offer, but it failed to do so. Consumers also opposed the Standard Offer presented by ELPC, alleging that the tariff, contained in Exhibit ELP-14 contains language that was not discussed by any party to this proceeding. Consumers raised particular concerns about ELPC's proposal to include language concerning the creation of a legally enforceable obligation (LEO) pursuant to PURPA, language that Consumers maintains was never addressed by any witnesses in this proceeding.

The Staff explained that for the capacity cost calculation, it used the same inputs that MISO used for 2017-2018 CONE, which were reasonable. However, in its brief, the Staff pointed out that the value for fixed O&M, as shown in Exhibit S-11, was incorrect. The Staff therefore recommended that the Commission adopt the fixed O&M input used by Consumers, combined with the Staff's MISO-based inputs for capital, heat rate, size, and performance characteristics.

For the energy portion of the calculation, the Staff recommends that the Commission adopt the 20-year natural gas forecast from the EIA that the Staff used in its calculation. The Staff contends that EIA data is reasonable and publicly available, whereas the company's information may be less reliable because Consumers is an interested party. The Staff reiterates that the use of a real, rather than nominal, price forecast is appropriate in developing avoided energy costs. For heat rate and plant capacity factor, the Staff again argues that unbiased, publicly-available information from the EIA should be used, rather than the estimates provided by the company. The Staff repeats that EIA information is more credible than the inputs advocated by the utility, which has a significant interest in the outcome of this proceeding. The Staff maintains that Consumers provided no evidence to show that the company's projections are more accurate than those provided by the EIA and used by the Staff in its calculation.

The Staff states that it continues to support the use of ELCC, expressed in ZRCs, for wind and solar resources. The Staff notes that adjusting the capacity factor based on actual generator performance does not violate the requirement under PURPA that the Standard Offer be fixed. The Staff also recommends that the Commission clarify that the Standard Offer is available to 2 MW AC or less QF facilities as recommended by ELPC, and the Staff concurred with ELPC's recommendation to include language indicating that an LEO under 18 CFR § 292.304(d) arises when a QF submits a written request for interconnection with the purchasing utility. The Staff also agreed with ELPC's recommendations regarding a timeframe within which a utility must execute an agreement, *e.g.*, within 10 days after a QF submits to the utility all of the information required under the Standard Offer. The Staff also agreed with the company's proposal that the Standard Offer tariff be made available five business days after the Commission issues a final order approving avoided costs. Finally, the Staff suggests that although the record contains levelized energy costs it would not oppose the use "of a non-levelized schedule of energy costs calculated, if agreed to by the other parties." Staff's brief, p. 12.

IPPC argues that the Commission should reject Consumers' proposed inputs to the NGCC and NGCT models, claiming that the company's inputs were chosen to result in the lowest possible avoided cost payments. According to IPPC, this violates PURPA mandates that avoided costs be just and reasonable to both the customers and the QFs, and that the rates not discriminate against QFs in favor of the company's generation. IPPC further contends that Consumers' continued insistence on using the MISO ZRC capacity structure for all QFs was not responsive to the Commission's order, where the Commission made clear that ZRC capacity credits should be applied to intermittent resources like solar and wind. Moreover, IPPC argues that "restricting capacity purchases for baseload generation by a reliance on ZRCs would violate PURPA if used[,]" noting that even the company admits that ZRCs are only bought or traded to address residual imbalances. IPPC's brief, pp. 9-10.

For the company's avoided energy costs, IPPC contends that the Commission should adopt the average annual heat rate that IPPC proposed, or it should adopt the 7,600 Btu/kWh heat rate that Consumers uses in the Filer City PPA amendment. IPPC also objects to Consumers' $7.65/kW-year fixed O&M cost, claiming that this amount is unreasonable and far below what the company pays for its own facilities, pointing to the fixed O&M that Consumers presented in Case No. U-17429, which, if inflated to 2017 dollars, would be $14.62/kW-year. Similarly, IPPC opposes Consumers recommended use of an 82% capacity factor for an NGCC, arguing that this factor is based on only one year of operating data at one plant.

IPPC argues that while it agrees with the Staff's levelized cost for natural gas, the Staff failed to include transportation costs in that value which, if included, would increase the cost from $4.76/MMBtu to $5.64/MMBtu. Moreover, IPPC asserts that the Commission should reject Mr. Harlow's corrected testimony concerning fuel costs and instead use his original testimony as explained by ELPC. IPPC also agrees with ELPC's recommendation to incorporate line losses, and recommends that the Commission adopt the Staff's Standard Offer tariff.

ELPC recommends that the Commission approve the following:

> (1) The Commission should include an input that accounts for demand losses in avoided capacity costs because demand losses are a type of line loss that occurs at peak load times. The Commission's Order indicated line losses should be accounted for, see Order at 26, and this data is readily available because the Company already calculates these values in its annual general rate case. See Jester 1 TR (Reopened) 58-61.

(2) The Commission should allow solar QFs to submit and the Company to approve Effective Load Carrying Capacity ("ELCC") based on the National Renewable Energy Laboratory ("NREL") System Advisor Model. While Joint Intervenors support an ELCC adjustment to calculate the capacity provided by intermittent renewable energy, MISO has not yet accumulated sufficient data on solar PV systems for the MISO method specified in its Business Practice Manual to accurately reflect solar capacity. See Jester 1 TR (Reopened) 61-65.

(3) The Commission should use Staff's initial June 12, 2017 testimony for avoided cost inputs because those calculations do not double-discount for inflation. Or, in the alternative, Joint Intervenors would not object to the use of an agreed-upon non-levelized schedule of energy costs calculated based on publicly available information. See Jester 2 TR (Reopened) 174-182.

(4) The Commission should use the most accurate and updated information available to calculate energy losses in avoided energy costs.

ELPC's brief, p. 2.

Discussion

After the determinations made in the May 31 order, the following issues require resolution: (1) the appropriate inputs to the NGCT model; (2) the application of the ZRC capacity structure to QF capacity; (3) appropriate inputs to the NGCC model, including fuel forecast, heat rate and NGCC capacity factor; and (4) Standard Offer tariff language and effective date. These issues are addressed *ad seriatim.*

1. Natural Gas Combustion Turbine Inputs

At the outset, the Commission rejects IPPC's and ELPC's proposals for calculating avoided capacity cost. As Consumers observes, IPPC's and ELPC's proposals do not comport with the May 31 order, which clearly directed the parties to provide proposed inputs for the hybrid proxy model the Staff proposed. In IPPC's case, it only provided inputs for an NGCC unit for both the capacity and energy calculations. In ELPC's case, while it considered both the NGCT and NGCC components, it introduced a new method for determining inputs and calculating avoided costs.

The Commission observes that the Staff's and the company's inputs for an NGCT are comparable; nevertheless, the Commission finds more persuasive the Staff's recommendation to use the Staff's inputs shown in Exhibit S-11, which are principally based on information provided by MISO in 2017, with the company's amount for fixed O&M costs as shown in Exhibit A-15. The Commission also finds that capacity payments should be expressed in $/ZRC-year, consistent with Exhibit A-30.

2. Application of Zonal Resource Credits

Consumers contends that because MISO assigns capacity to the company on the basis of ZRCs, the same ZRC capacity construct should be used for all QF facilities. The company adds that even if the Commission applies the ZRC capacity credit only to intermittent resources, the Commission should also include run-of-the-river hydro as an intermittent resource, explaining that MISO considers these QFs to also be intermittent, like solar and wind. ELPC appears to agree generally with Consumers' position but recommends that the Commission make a specific calculation (SAM) for solar resources. IPPC objects to any application of ZRCs, contending that ZRCs simply represent incremental capacity assigned by MISO when the company has a shortfall. IPPC therefore urges the Commission to reaffirm the May 31 order and apply ZRC capacity credits only to wind and solar QFs.

The Commission finds that its initial regulatory response, limiting the use of the ZRC capacity structure to intermittent resources like wind and solar, merits revisiting. On reconsideration, the Commission finds that the MISO ZRC capacity construct should be applied to all QFs entering new contracts. While IPPC's contention that ZRCs are traded or sold in the PRA to cover incremental capacity shortfalls is true, that is not their sole function. As Ms. Thyagarajan testified:

> The Company receives capacity credit from MISO for all generating units, regardless of fuel type or intermittency, based on ZRCs awarded to each resource

> through MISO's capacity planning construct. Since the Company and its customers receive capacity credit based on the ZRCs, the QF can deliver to the Company in each MISO planning year, capacity payments to QFs should not be based on nameplate capacity.

1 Tr 19. While PURPA requires that QFs are not discriminated against in contracts for capacity and energy; the reverse is also true, and the rates paid to QFs should not favor these resources over company-build resources or non-QF PPAs. In this case, the Commission sees no justification to limit the application of ZRC capacity credits to only wind and solar, especially considering the fact that MISO applies ZRCs to all generating units, whether company-owned or not. Therefore, the Commission agrees with Consumers that the ZRC capacity construct should be applied to all QF generators. Accordingly, Consumers shall revise the Standard Offer to reflect this determination.

The Commission rejects ELPC's proposal to use an engineering analysis based on the SAM model for solar resources. While MISO assumes a capacity factor of 50% for solar in the first year, once a history is established, the capacity credit is adjusted based on actual generator availability.

The Commission recognizes that for certain existing QFs, particularly run-of-the-river hydro, the application of MISO capacity credit represents a significant departure from the way that capacity was valued in the past. Accordingly, and as discussed in more detail *infra*, run-of-the-river hydro <u>only</u> may opt for a levelized energy payment in lieu of an escalating payment.

3. Natural Gas Combined Cycle Inputs

As discussed above, ELPC provided an alternative method for calculating the energy portion of the avoided cost calculation, which did not comport with the Commission's directive in the May 31 order. However, Consumers, the Staff, and IPPC did provide proposed inputs for calculating avoided energy cost based on an NGCC. The disputed inputs are the appropriate heat rate, assumed capacity factor of the NGCC, and fixed and variable O&M costs. The controversy over these issues centers, to a large extent, on which source, company-developed or publicly-available, should be used for these components of the calculation. Consumers insists that its inputs are the only correct ones because they were developed internally and are specific to the type of unit the company would build. On the other hand, the Staff's inputs rely primarily on information available from the EIA, coupled with Consumers' fixed charge and discount rates. IPPC uses a combination of sources to derive its recommendations.

In its calculation, Consumers used a heat rate of 6.354 MMBtu/Mwh, an amount that the company claimed was comparable to the EIA estimate of 6.300 MMBtu/MWh for an advanced NGCC unit. Consumers noted in its initial brief, however, that there may be merit to using an average annual heat rate, which should not exceed 6.600 MMBtu/MWh. The Staff assumed a heat rate of 6.719 MMBtu/MWh, based on EIA information for a generic NGCC unit. IPPC proposed a heat rate of 7.600 MMBtu/MWh based on the Filer City PPA.

The Commission agrees with Consumers that the heat rate contained in the Filer City PPA amendment is not appropriate for use in this avoided cost proceeding. As Consumers points out, the heat rate used in the PPA was a negotiated term that may not reflect the actual heat rate of the Filer City plant. The Commission also agrees with the company that the EIA information that the Staff used does not appear to reflect the heat rate of an advanced unit, but rather of a generic NGCC. On the other hand, there is no way of knowing at this juncture the precise type of plant that the company would potentially build or the heat rate of that plant. The Commission agrees with Mr. Vine, however, that the average annual heat rate, and not the heat rate at maximum output, is the most appropriate for use in determining avoided cost. As Mr. Vine explained:

> NGCCs, like many thermal plants, lose efficiency at lower output levels and varying ambient conditions. An NGCC plant will only achieve its ideal heat rate at

> full load and at ideal ambient temperature and humidity. Many plants will typically operate at full output only during peak hours, and then operate at a lower output level during off peak periods.

2 Tr 138.

In its brief, Consumers conceded that:

> While the Company believes that there may be some merit to using an average annual heat rate, none of the data submitted from the vendors supports an average annual heat rate above 6.600 MMBtu/MWh.

Consumers' brief, p. 9. Accordingly, as a reasonable heat rate that falls between the company's original recommendation, and that of the Staff, the Commission adopts a heat rate of 6.600 MMBtu/MWh for use in calculating avoided energy cost in this proceeding and finds that this issue should be examined in more detail in the company's next PURPA review.

With respect to NGCC operating characteristics, Consumers maintains that the Staff's proposed 61.77% capacity factor is far too low based on current market conditions and the likely capacity factor for the H-class NGCC unit that the company would build. Consumers recommends that the Commission adopt a capacity factor of 82%, which corresponds to the 2016 capacity factor for Consumers' Zeeland plant. The Staff responds that its value comes from EIA, a neutral, public source, whereas the company's capacity factor assumption is proposed by an interested party. IPPC similarly contends that the company used only one year of Zeeland operational data in order to support its position, and that a multi-year average demonstrates a much lower capacity factor for that plant.

The Commission agrees with the Staff that the information on capacity factor available from EIA for an NGCC unit is most appropriate for use here. As the Staff again points out, there is no way of knowing the capacity factor for any NGCC unit Consumers might build, and there is no doubt that the company is an interested party to this proceeding. And, although there is nothing in the record concerning the average capacity of the Zeeland plant calculated over several years, it would certainly seem that a longer-term assessment would be more appropriate, rather than the single year of operating data that Consumers offered. Accordingly, the Commission adopts the Staff's capacity assumption of 61.77%.

There was significant dispute among the parties about the natural gas forecast input and whether it should be expressed in real, rather than nominal, dollars. In addition, IPPC raises the concern that the forecasts presented do not include transportation costs.

In his corrected testimony, Mr. Harlow explained that the Staff used the real natural gas EIA forecast from the 2017 EIA Annual Energy Outlook, noting that in calculating transfer price for Act 295 purposes the Staff uses the nominal price forecast. According to Mr. Harlow, "the nominal price forecast would be appropriate if it were utilized on a net present value (NPV) basis only, but since Staff takes the NPV of the gas forecast and applies a change rate based on Global Insight indices that assume an inflation rate, the real price forecast is appropriate for this purpose." 1 Tr 42.

Consumers agreed with the Staff's approach, observing:

> [W]hen calculating levelized energy prices, and subsequently escalating that price, a real dollar gas price forecast is most accurate. This is because, in order to correctly account for the time-value of money, it is only reasonable to use real dollar forecasts in calculating a levelized energy price which is then subsequently escalated. Using nominal dollars would only be appropriate if the calculated levelized price was being proposed for energy payments in every year of the contract term. . . . [I]f the nominal price of natural gas is levelized and then further escalated, it results in double-counting the impacts of escalation.

Consumers' brief, pp. 17-18.

ELPC criticized the Staff's use of a real price forecast, with a nominal discount rate, contending that this method discounts inflation twice. Instead, ELPC suggests that the Staff should have used a real price forecast with a real discount rate. ELPC contended that the

Commission should use the Staff's initial forecast (Exhibit S-7) which was based on a nominal forecast and a nominal discount rate. ELPC further noted that "based on continuing discussions with Staff, the Company and other intervenors, [ELPC] would not object to the use of an agreed-upon non-levelized schedule of energy costs calculated based on publicly available information." ELPC's brief, p. 7.

Consumers agreed that although there may be some merit to using real prices and a real discount rate, ELPC failed to provide any discount rate in its testimony. Moreover, Consumers contends that there would be little cost difference between the approaches. IPPC concurred with ELPC that the Staff's purportedly corrected inputs were erroneous, further noting that the updated forecast results in a reduction in avoided energy costs of approximately 20%.

The Commission agrees with the Staff and Consumers that in calculating a levelized avoided cost of natural gas, Mr. Harlow's approach, set forth in his corrected testimony and supported by Consumers, is the appropriate method. As Consumers explained:

> There are three methods that can appropriately be used to account for escalation. Ms. Thyagarajan stated:
>
> "(1) using real dollar forecasts for the levelized price calculation, then applying escalation – as shown in Exhibit A-31 (PDT-18), column (f); (2) using nominal dollar forecasts for the levelized price calculation, without applying escalation – as shown in column (g); or (3) not levelizing costs at all, and using the nominal price forecasts on an annual basis over the contract term – as shown in column (d)." 2 TR 99.
>
> Any of these methods would result in the accurate accounting for escalation. However, given that the Commission has indicated its intent to escalate the levelized energy payment (May 31, 2017 Order, page 18), only method one described above is reasonable.

Consumers' brief, p. 18.

However, the Commission recognizes IPPC's concern that the levelized fuel cost calculated by the Staff appears not to include the cost of transportation. Thus, as discussed below, the natural gas price forecast shall be updated to include transportation. In addition, gas prices shall be provided on both a real and nominal basis, and the parties shall present a final, variable O&M cost, again on a levelized basis and as a schedule.

Finally, both the Staff and ELPC suggest in their briefs that it would not be unreasonable to use a schedule of energy payments, rather than converting the amount to a levelized payment over the term of the contract. The Commission agrees, and finds that its initial regulatory response to whether energy avoided cost should be levelized, or based on a schedule of payments, merits reconsideration. As Consumers explained in its initial brief, p. 11, in the previous contested proceeding:

> [I]t is unnecessary to levelize . . . energy payments because annual (or monthly) ongoing expenses provide the most accurate reflection of the avoided variable costs to generate electricity or fixed O&M costs of plant personnel to customers. By levelizing the payments for these types of costs, payments to QFs are front-loaded. This is particularly problematic when applied to costs not associated with the upfront capital investment necessary to construct a facility. By making levelized payments for fuel and Operation and Maintenance ("O&M"), the Company and the Commission would effectively be asking the QF to manage year-to-year fluctuations in fuel and O&M expenses.

Unfortunately, the reopened record lacks some of the required information to develop such a schedule. Therefore, the Commission again remands this case for the development of a final energy avoided cost schedule, based on the determinations made in this order, coupled with the schedule of nominal gas prices for 2017 from EIA. As it has discussed previously, the Commission has a preference for publicly available information, which is consistent with EIA information. The parties shall file testimony and exhibits for this second reopened proceeding by August 11, 2017. Rebuttal shall be filed by August 21, 2017. The ALJ shall conduct an evidentiary hearing on August 30, 2017.

Accordingly, for QFs (e.g., run-of-the-river hydro only) that may opt for levelized energy payments based on the avoided cost of a proxy NGCC, the Commission adopts the amounts shown on Exhibit S-12, p. 3, adjusted for the determinations made in this order.

5. Standard Offer Tariff

The Commission rejects IPPC's request to make the Standard Offer subject to further revision through a technical conference. As Consumers points out, IPPC has had the opportunity to present a tariff or provide comments on the proposed tariffs presented by the Staff and Consumers, in both phases of this proceeding, but it declined to do so. In addition, the Commission agrees with Consumers that language concerning when an LEO is created was not sufficiently addressed here, thus the Commission declines to include this language in the Standard Offer. Instead, the Commission directs interested parties to raise this issue in Consumers' biennial review.

After reviewing the tariffs offered by Consumers, the Staff, and ELPC, the Commission finds that the Staff's proposed Standard Offer tariff, set forth in Exhibit S-9, updated to reflect the determinations in this order, and amended to include the modifications proposed by Consumers,[3] as well as the clarifications regarding design capacity (2 MW AC), should be approved. The Commission also agrees with ELPC's recommendation to include language setting a timeframe for executing a Standard Offer agreement, as set forth on Exhibit ELP-14, p. 5.

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[3] The Commission agrees that for the 15 and 20 year LMP forecasts, Consumers' projections should be used, updated to include a final amount for ICE and line losses.

THEREFORE, IT IS ORDERED that:

A. On or before August 11, 2017, the parties to this proceeding may file testimony and exhibits supporting forecasted natural gas prices, including a levelized energy payment, a proposed energy payment schedule, and final standard offer tariff based on their proposals.

B. Parties to this proceeding may file responses to the initial filings by August 21, 2017.

C. A hearing shall be conducted by Administrative Law Judge Mark E. Cummins at 10:00 a.m. on August 30, 2017. At the hearing, the Administrative Law Judge shall set a briefing schedule so that the Commission can read the record and issue a decision by September 28, 2017.

The Commission reserves jurisdiction and may issue further orders as necessary.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

Rachael A. Eubanks, Commissioner

By its action of July 31, 2017.

Kavita Kale, Executive Secretary